US009470074B2

(12) United States Patent
Bolding et al.

(10) **Patent No.: US 9,470,074 B2**
(45) **Date of Patent: Oct. 18, 2016**

(54) **DEVICE AND METHOD FOR IMPROVING GAS LIFT**

(71) Applicant: **DROVER ENERGY SERVICES LLC**, Kilgore, TX (US)

(72) Inventors: **Jeffrey L. Bolding**, Kilgore, TX (US); **Joseph D. Clark**, Kilgore, TX (US)

(73) Assignee: **Drover Energy Services LLC**, Kilgore, TX (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 156 days.

(21) Appl. No.: **14/298,431**

(22) Filed: **Jun. 6, 2014**

(65) **Prior Publication Data**

US 2015/0354325 A1 Dec. 10, 2015

Related U.S. Application Data

(60) Provisional application No. 61/832,420, filed on Jun. 7, 2013.

(51) **Int. Cl.**
E21B 43/12 (2006.01)
E21B 23/03 (2006.01)

(52) **U.S. Cl.**
CPC ***E21B 43/122*** (2013.01); ***E21B 23/03*** (2013.01)

(58) **Field of Classification Search**
CPC E21B 43/12; E21B 43/122; E21B 43/16; E21B 33/12; E21B 34/06; E21B 23/03
See application file for complete search history.

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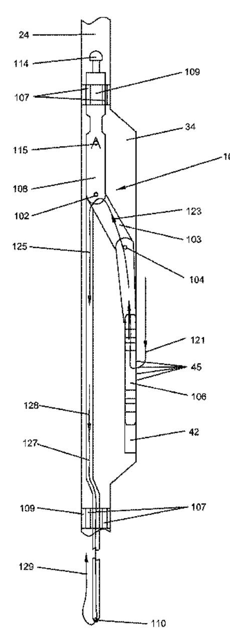
Primary Examiner — Yong-Suk (Philip) Ro
(74) *Attorney, Agent, or Firm* — The Kubiak Law Firm, PLLC

(57) **ABSTRACT**

A device and method to lower the deepest gas lift location to a deeper location within the wellbore. Providing a bottom lift tool with flexible joints to sting into a side pocket mandrel to access annular high pressure gas. Diverting that gas into the stinger through the bottom lift tool down into the wellbore below the lowest end of the production tubular and the packer and preferably to at least the bottom of the perforations in the casing.

20 Claims, 8 Drawing Sheets



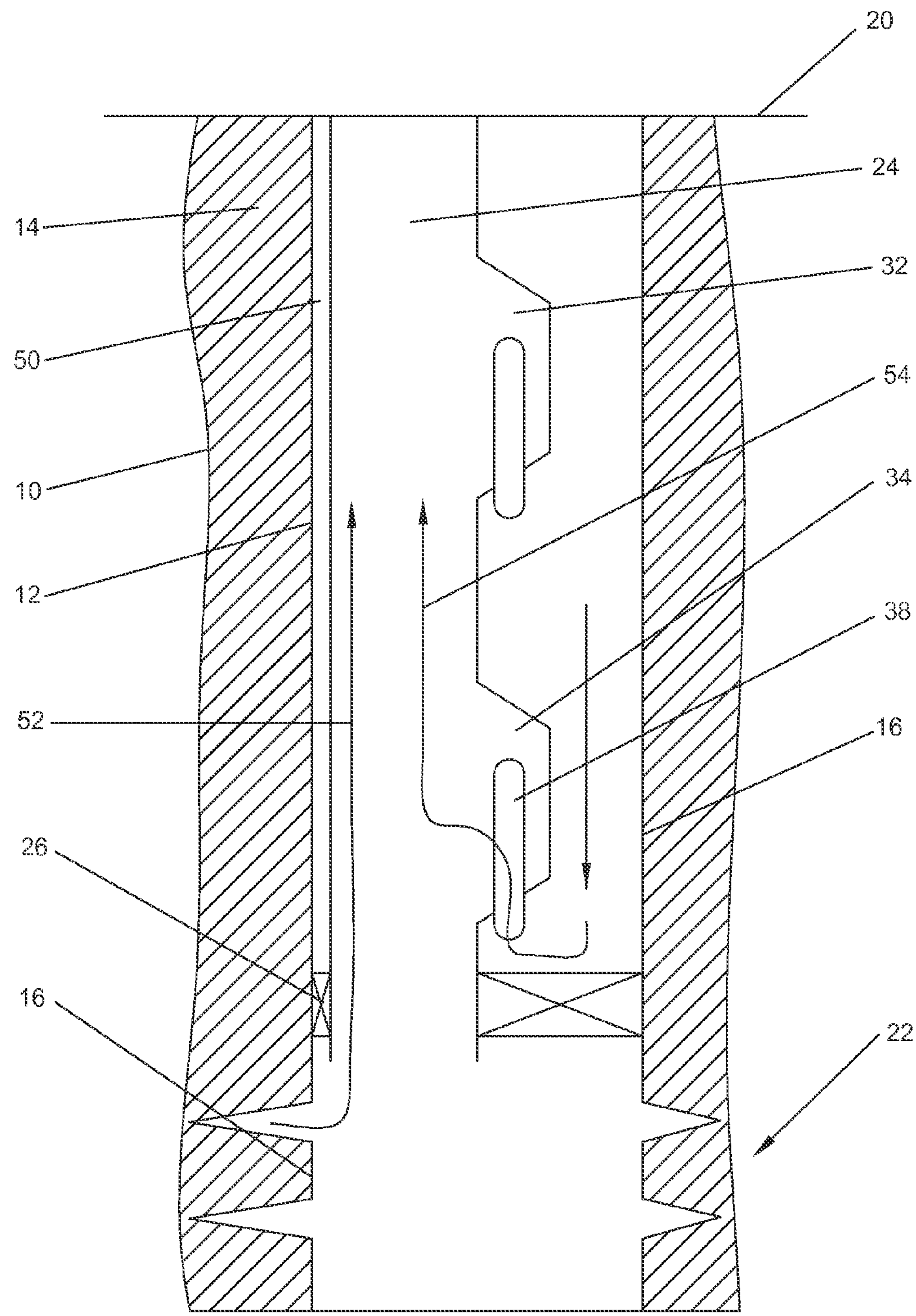


Figure 1

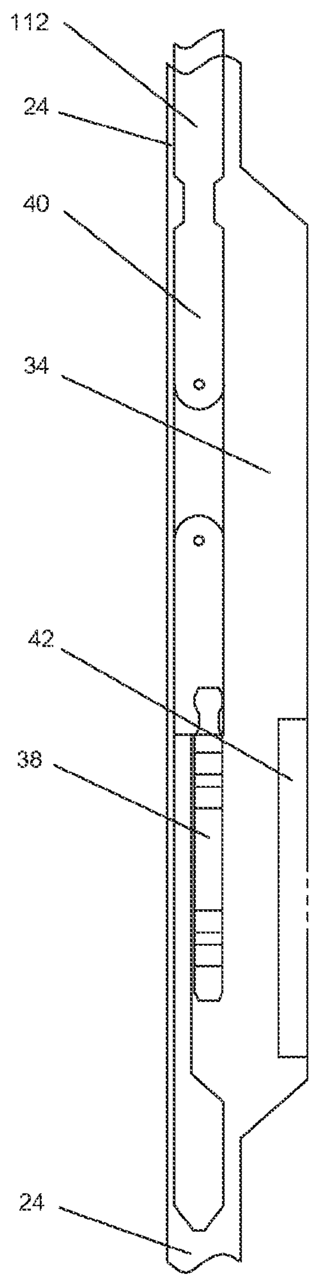


Figure 2

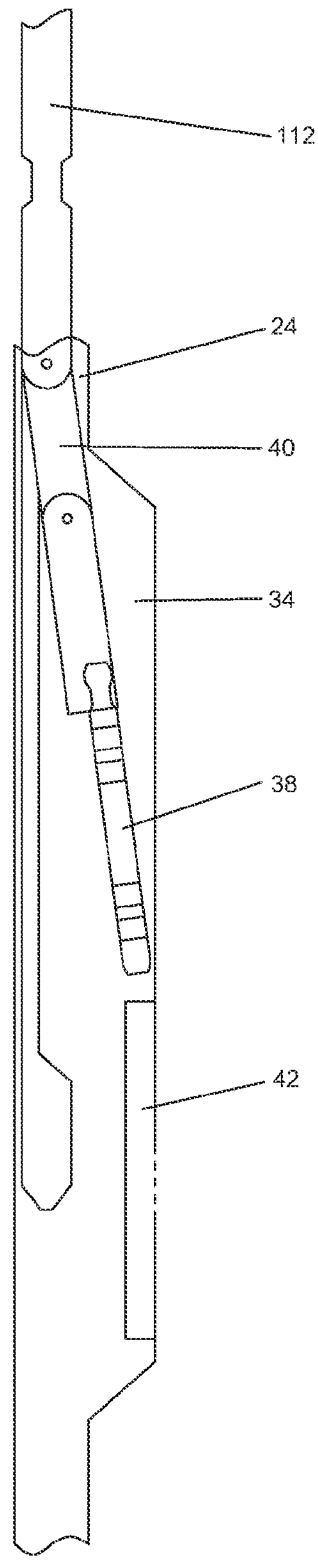


Figure 3

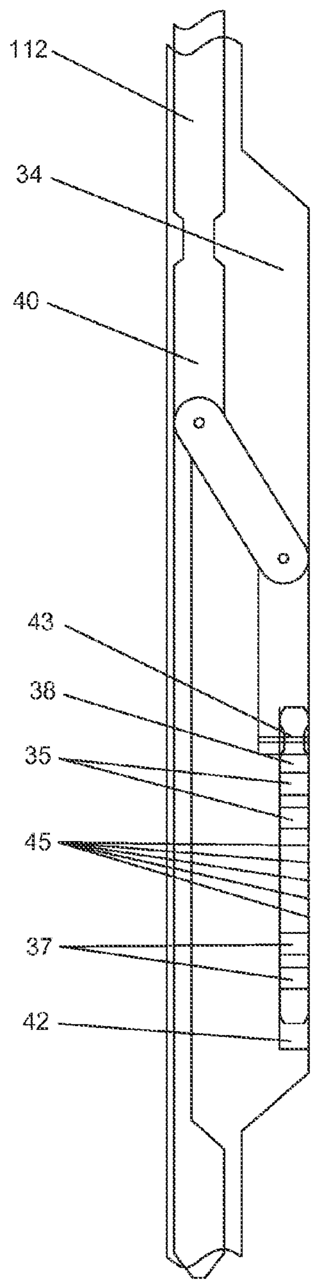


Figure 4

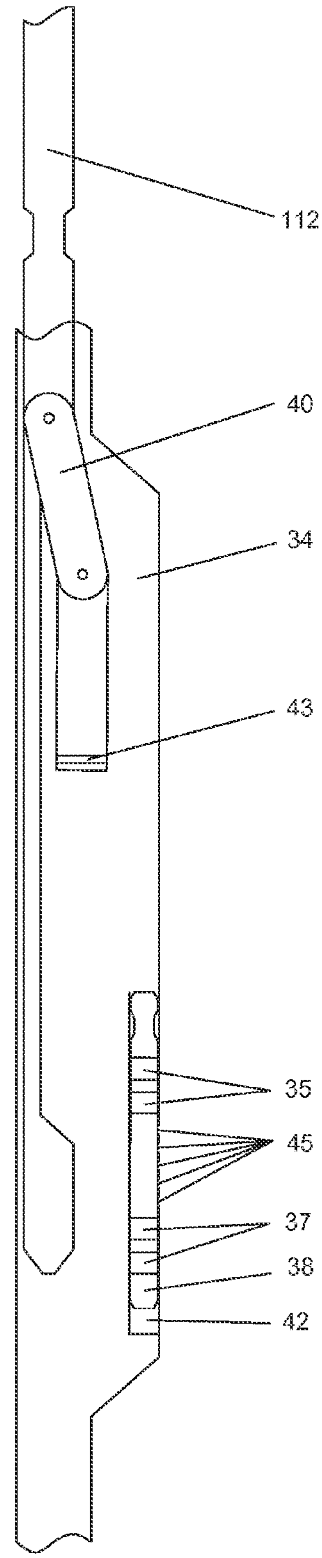
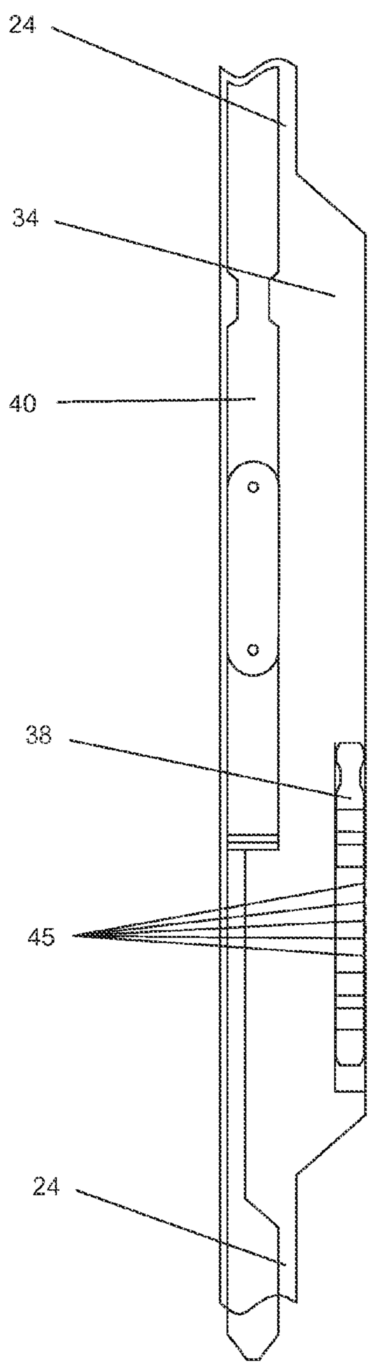


Figure 5



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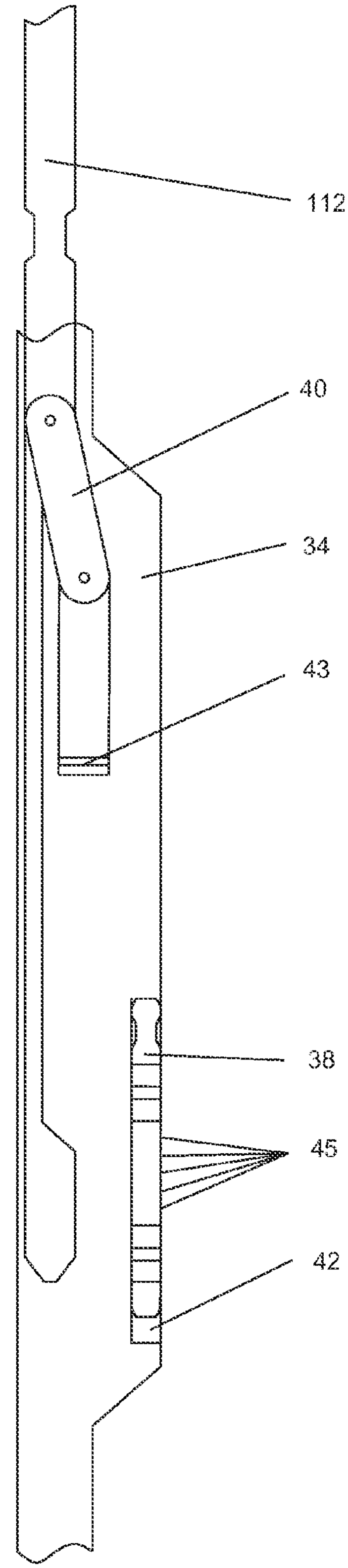
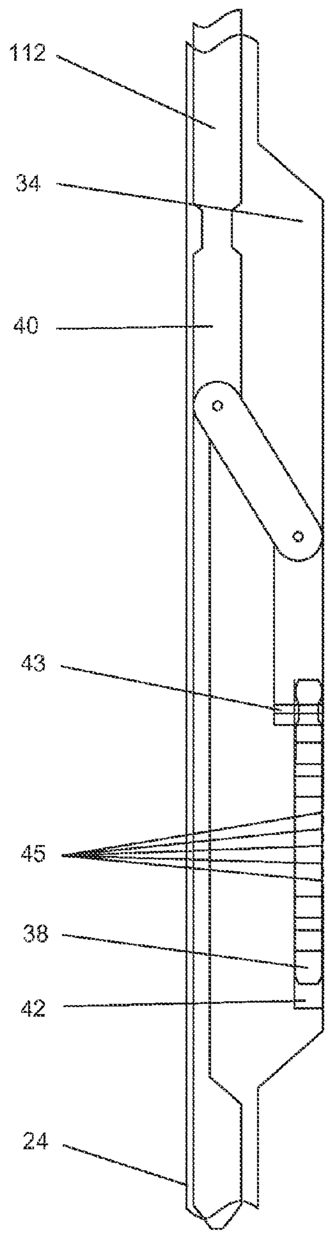


Figure 7



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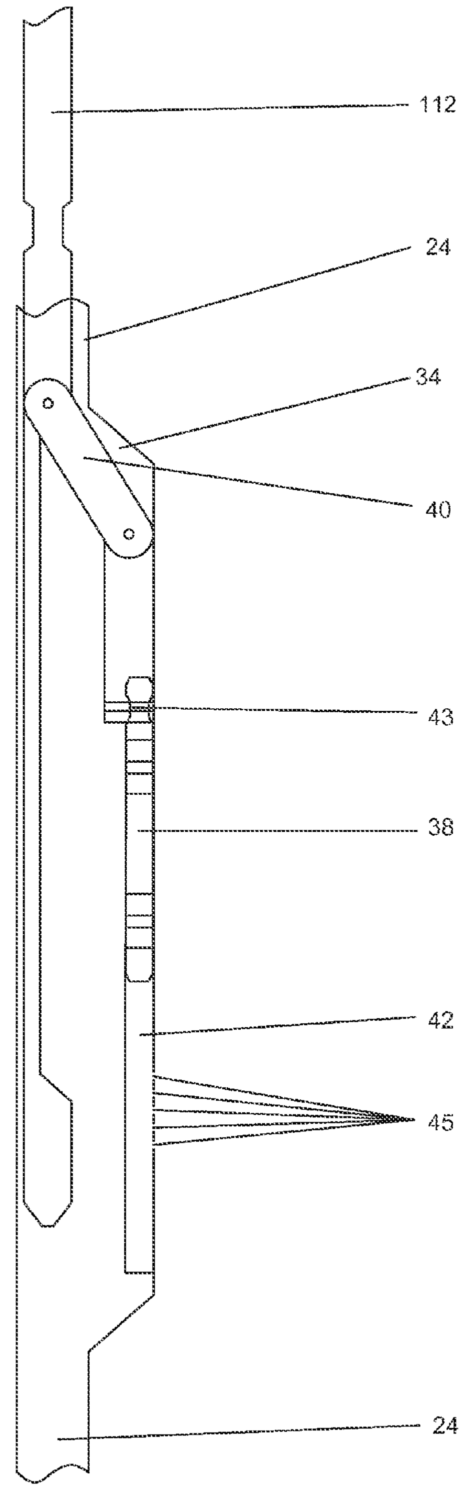


Figure 9

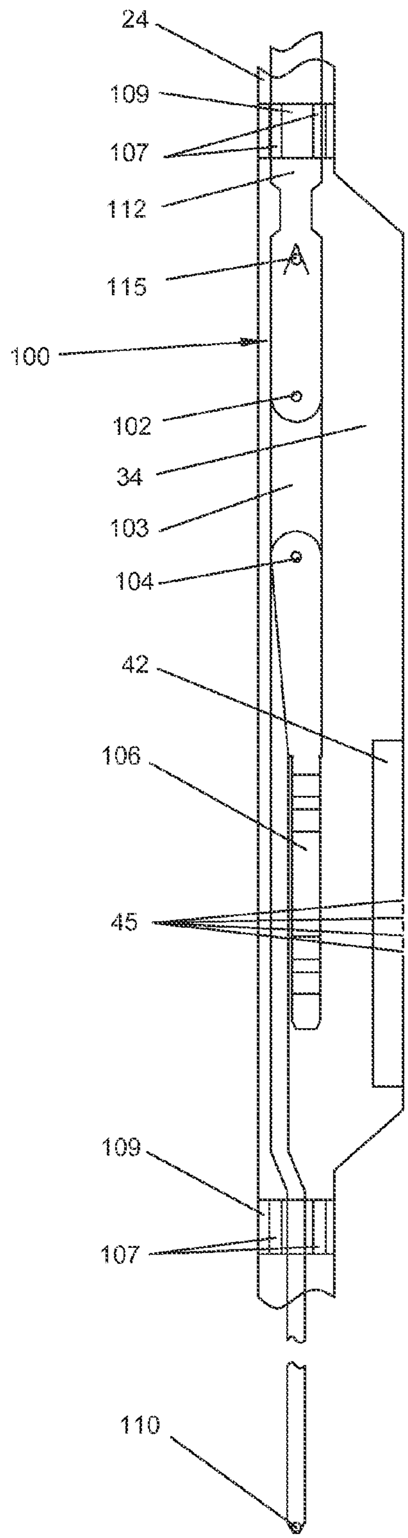


Figure 10

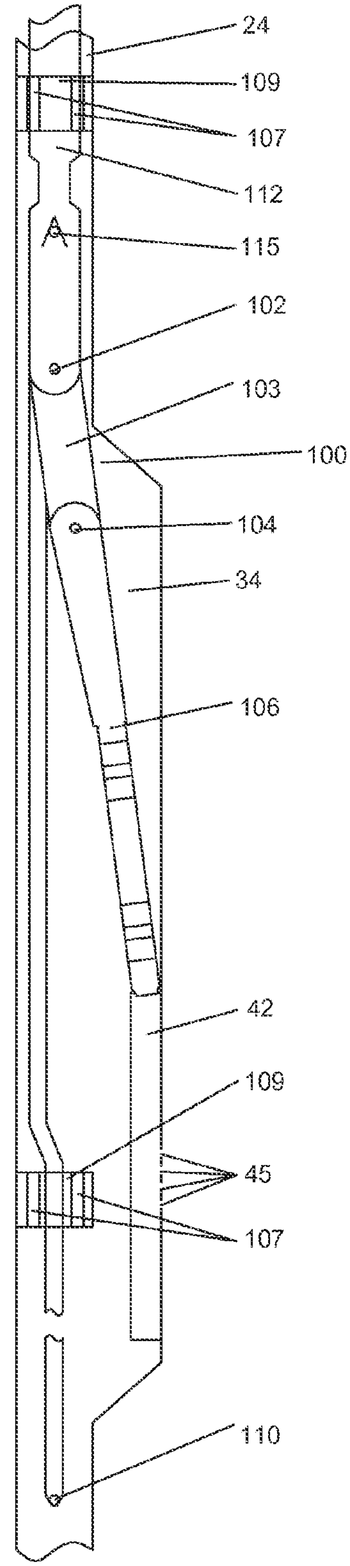
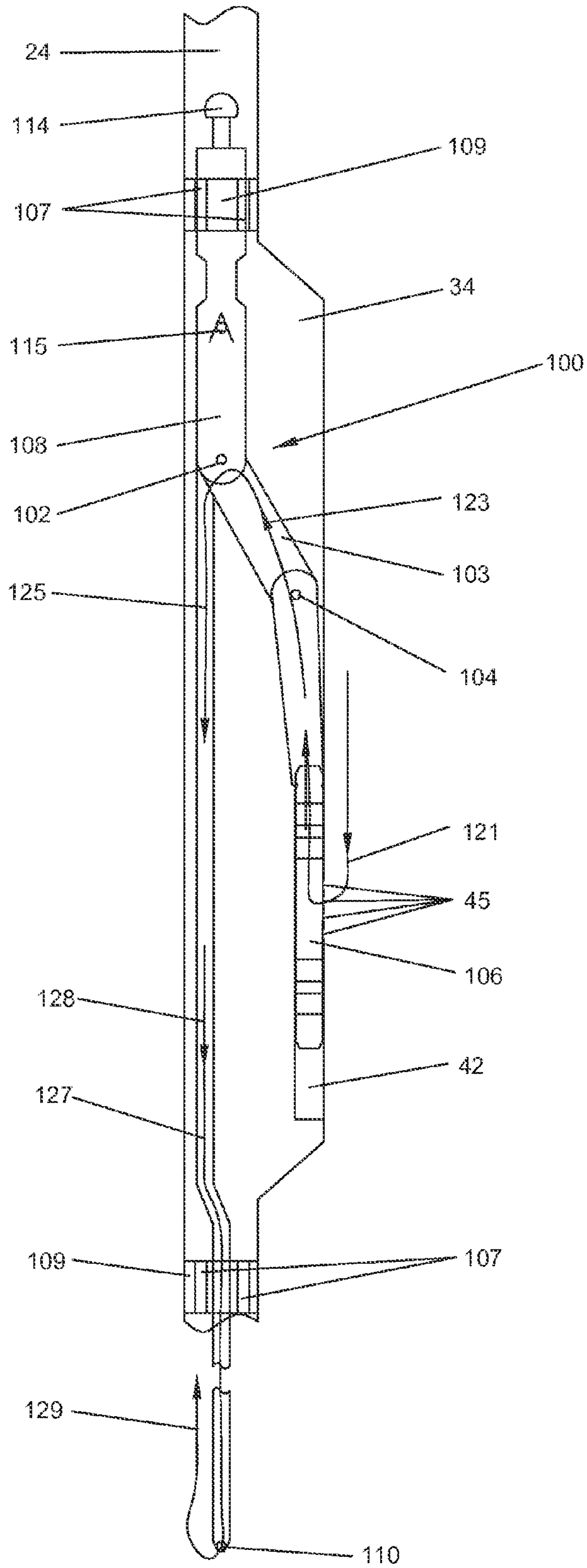


Figure 11


24
114
109
107
34
115
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110

Figure 12

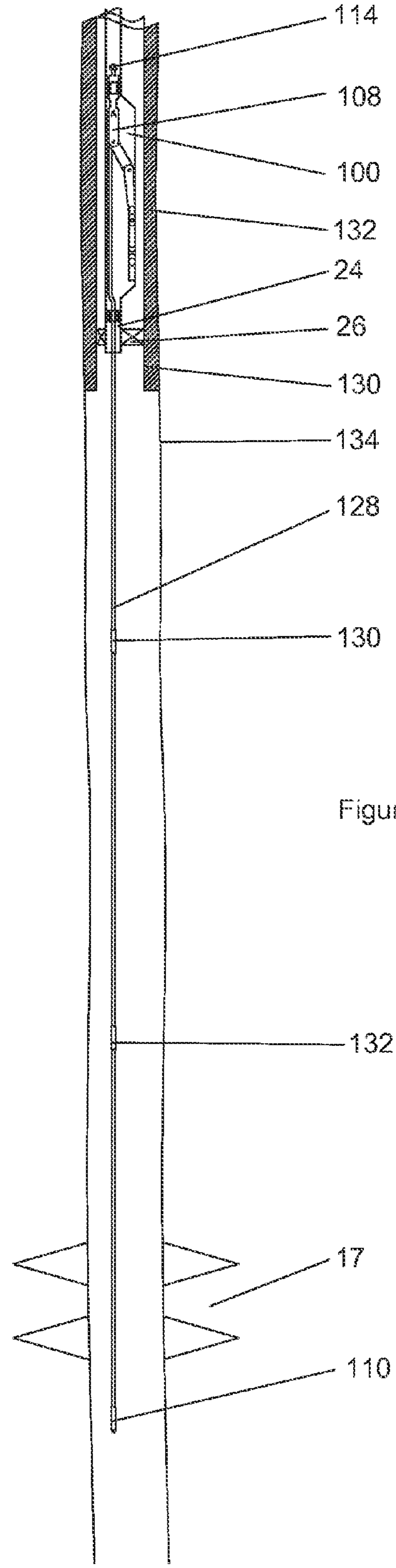

Figure 13

DEVICE AND METHOD FOR IMPROVING GAS LIFT

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims priority to U.S. Provisional Patent Application No. 61/832,420 that was filed on Jun. 7, 2013.

FIELD OF INVENTION

Embodiments of the present invention generally relate to methods and apparatuses for a downhole operation. More particularly, the invention relates to methods and apparatuses for providing gas lift where gas is provided via an annular region accessed by a side pocket mandrel.

BACKGROUND

Many hydrocarbon producing wells around the world, require artificial lift. A common form of artificial lift is gas lift. The purpose of a gas lift system is to introduce gas below the fluid column in order to increase the velocity of the fluid, thereby lifting the fluid to the surface. Gas lift systems typically have several gas injection points along the length of the fluid column in the wellbore.

Typically the production tubing is run inside the cased well preferably terminating just above the perforations in the casing. At the lower end of the production tubing a packer is utilized to seal the lower end of production tubing to the casing. The gas injection points typically consist of side pocket mandrel's with gas lift valves in each side pocket.

With the gas lift system in operation, pressurized gas is supplied to the annular region formed between the exterior of the production tubing and the interior of the casing. The packer at the lower end of the production tubing prevents the pressurized gas from flowing into the formation. Typically the only pathway for the pressurized gas to flow is through the gas lift valves in the side pocket mandrels. As the pressurized gas enters the fluid column through the gas lift valves, the fluid column is lightened by mixing gas with the fluid, increasing the velocity of the fluid as it moves upward in the production tubing thereby lifting fluid out of the well.

Because the pressurized gas is supplied through the annular area between the production tubing and the casing, the pressurized gas supply is typically limited to the area above the packer. Commonly the packer may be set 100 feet above the perforations through the casing. However in some instances, the distance from the packer to the bottom perforations can be quite large, in some cases as much as 1000 feet or more. As the well is depleted, the natural fluid level of the well may be lower than the lowest injection point in the gas lift system thereby rendering the gas lift system virtually useless and thereby rendering the fluid remaining in the well below the packer essentially unrecoverable by current gas lift methods.

The current invention describes an apparatus and method to lower the initial gas lift location to a deeper location within the wellbore that in many instances is below the packer and below the bottom of the production tubular.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** depicts a typical gas lift system.

FIG. **2** depicts the initial stage of the installation of a gas lift valve.

FIG. **3** depicts the second stage of the installation of the gas lift valve

FIG. **4** depicts the third stage of the installation of the gas lift valve.

FIG. **5** depicts the fourth stage of the installation of the gas lift valve.

FIG. **6** depicts the first stage of retrieving a gas lift valve with the kick over tool.

FIG. **7** depicts the second stage of retrieving a gas lift valve with the kick over tool.

FIG. **8** depicts the third stage of retrieving a gas lift valve with the kick over tool.

FIG. **9** depicts the fourth stage of retrieving a gas lift valve with the kick over tool.

FIG. **10** depicts an embodiment of the current invention where the kick over tool has been replaced by a bottom lift tool.

FIG. **11** depicts the bottom lift tool in the second stage of its installation in the side pocket mandrel.

FIG. **12** depicts the bottom lift tool in the final stage of its installation in the side pocket mandrel.

FIG. **13** depicts an extended length bottom lift tool having multiple gas lift valves along its length.

DETAILED DESCRIPTION OF THE INVENTION

FIG. **1** depicts a typical gas lift system. A wellbore **10** has a casing **12** that is run from the surface **20** through the formation zone **22**. Cement **14** holds the casing **12** in place and prevents the migration of wellbore fluids upwards between the casing **12** and the wellbore **10**. The casing **12** has perforations **16** to allow access from the formation zone **22** to the interior of the casing **12**. A production tubular **24** is run into the casing **12** from the surface **20**. A packer **26** is run in into the casing **12** on the production tubular **24** near or at the lower end of the production tubular **24**. The production tubular **24** has at least one side pocket mandrels. In FIG. **1**, two side pocket mandrels **32**, and **34** are shown.

FIG. **2** depicts the initial stage of the installation of a gas lift valve **38** in the side pocket mandrel **34**. As the kick over tool **40** is run into the production tubular **24** on e-line, slick line, coil tubing, or any other means known in the industry, it is run slightly past the side pocket mandrel **34** in order to facilitate the location of the side pocket mandrel **34**.

FIG. **3** depicts the second stage of the installation of the gas lift valve **38** in the side pocket mandrel **34**. The kick over tool **40** has been longitudinally located at the side pocket mandrel **34** and has been rotated to orient the gas lift valve **38** into the side pocket **42**. The kick over tool **40** then kicks out the gas lift valve **38**.

FIG. **4** depicts the third stage of the installation of the gas lift valve **38** in the side pocket mandrel **34**. With the gas lift valve **38** kicked out into the side pocket mandrel **34** the kick over tool **40** is jarred down so that the gas lift valve **38** is set into the side pocket **42** so that seals **35** and **37** on the gas lift valve straddle the inlets **45**. Seals **35** and **37** allow pressurized gas to flow in from the annular area and into the gas lift valve **38**. The pressurized gas then typically flows upward through the gas lift valve where the pressurized gas may be regulated before being injected into the fluid stream adjacent the side pocket mandrel **34**. Additionally, a release device **43** such as a shear pin, sheer screw, C ring, or other release device is actuated to release the kick over tool **40** from the gas lift valve **38**.

FIG. **5** depicts the fourth stage of the installation of the gas lift valve **38** in the side pocket mandrel **34**. With the gas lift valve **38** installed in the side pocket **42** and the kick over tool **40** released from the gas lift valve **38** the kick over tool **40** is then retrieved to the surface **20**.

Referring back to FIG. **1** with the gas lift valve **38** installed in the side pocket **34** the operator may begin to utilize the gas lift system by pressurizing the annular area **50** formed between the production tubular **24** and the casing **12**. The packer **26** below the lowest side pocket mandrel **34** prevents the pressurized gas in the annular area **50** from flowing into the formation zone **22**. As fluid from the formation zone **22** flows through perforations **16** and into the casing **12** it moves into the production tubing **24** upwards past the lowest side pocket mandrel **34**. Fluid flow is depicted by arrow **52**. The pressurized gas in the annular area **50** flows in to the side pocket via inlets **45** then into and through the gas lift valve **38** in side pocket mandrel **34** to mix with the fluid from the formation zone **22** to both reduce the density of the fluid thereby lightening the column of liquid that must move upwards to the surface **20** and increases the fluids velocity. The pressurized gas flow through gas lift valve **38** is depicted by arrow **54**.

At some point in the life of the gas lift system it may be necessary to change the gas lift valve **38** so that a new gas lift valve may be installed in the side pocket mandrel. New gas lift valves may be required for instance due to corrosion, valve failure, larger flow ports are necessary, smaller flow ports are necessary, or to install an embodiment of the invention as further described below.

FIG. **6** depicts the first stage of retrieving a gas lift valve **38** with the kick over tool **40**. As the kick over tool **40** is run into the production tubular **24** it is run slightly past the side pocket mandrel **34** in order to facilitate the location of the gas lift valve **38** in the side pocket mandrel **34**.

FIG. **7** depicts the second stage of retrieving a gas lift valve **38** with the kick over tool **40**. The kick over tool **40** has been longitudinally located at the gas lift valve **38** and has been rotated to orient the release device **43** into the side pocket **42** and towards the top of the gas lift valve **38**.

FIG. **8** depicts the third stage of retrieving a gas lift valve **38** with the kick over tool **40**. With the release device **43** kicked out into the side pocket mandrel **34** and towards the top of the gas lift valve **38** the kick over tool **40** and thus the release device **43** are jarred down so that the release device **43** latches onto the top of the gas lift valve **38**. Subsequent jarring unsets the gas lift valve **38**.

FIG. **9** depicts the fourth stage of retrieving the gas lift valve **38** from the side pocket mandrel **34** with the kick over tool **40**. With the gas lift valve **38** latched into the retrieving device **43** and unset from the side pocket mandrel **34** the kick over tool **40** and the gas lift valve **38** may be retrieved to the surface **20**.

FIG. **10** depicts an embodiment of the current invention where the kick over tool has been replaced by a bottom lift tool **100**. The bottom lift tool **100** has a stinger **106** at the upper end of the stinger **106** is a high pressure swivel **104** at the upper end of the high pressure link **103** is a second high pressure swivel **102** which in turn is connected to bottom lift injector **110**. Bottom lift injector **110** typically extends some distance, possibly hundreds of feet, below the inlets **45** and more preferably extend below the formation zone (not shown). The stinger **106** may simply be a connection to sting into the gas lift mandrel **34** or it may be a gas lift valve to control the flow from the annulus into the bottom lift tool **100**. In certain instances either high pressure swivel **102** or **104** could be replaced with a high pressure hose or other flexible conduit. In certain instances the entire assembly high pressure swivel **102** high pressure link **103** and high pressure swivel **104** could all be replaced with a high pressure hose or other flexible conduit. Typically the bottom lift injector **110** is attached to or is a part of coil tubing between three quarters of an inch and 1 inch outer diameter although larger or smaller diameters may be used.

The bottom lift tool **100** has a body **108**. In many instances the body **108** has a check valve **115** to relieve pressure from the inner bore of the bottom lift tool **100**, see FIG. **12** Typically the bottom lift tool **100** has a standard size. In order to allow a standard size bottom lift tool **100** to be run into any larger size tubular interchangeable centralizer rings **109** may be provided. Typically the centralizer rings **109** are roller bogey centralizer rings and have vertical grooves or ports **107** to allow fluid to flow past the centralizer rings **109** as the bottom lift tool is run into the hole as well as when fluid is produced out of the well past the bottom lift tool.

FIG. **10** depicts the bottom lift tool **100** in the first stage of its installation in the side pocket mandrel **34**. As the bottom lift tool **100** is run into the production tubular **24** on a work line **112** such as e-line, slick line, coil tubing, or any other means known in the industry, it is run slightly past the side pocket mandrel **34** in order to locate the stinger **106** to the side pocket mandrel **34**.

FIG. **11** depicts the bottom lift tool **100** in the second stage of its installation in the side pocket mandrel **34**. The stinger **106** has been longitudinally located to the side pocket mandrel **34** and has been rotated to orient the stinger **106** into the side pocket **42**. The bottom lift tool **100** then kicks out the stinger **106**.

FIG. **12** depicts the bottom lift tool **100** in the third stage of its installation in the side pocket mandrel **34**. With the stinger **106** kicked out into the side pocket mandrel **34** the bottom lift tool **100** is jarred down so that the stinger **106** is set into the side pocket **42**. A release device **114** such as a fishing neck, shear pin, sheer screw, C ring, or other release device is typically located at the upper end of the bottom lift tool **100** and where the bottom lift tool **100** is sized so that the release device **114** will be below the upper end of the side pocket mandrel **34** thereby providing a less restricted pathway for fluid to flow past the bottom lift tool **100** when the work line **112** is pulled out of the hole. The release device **114** may be actuated to release the bottom lift tool **100** from the work line **112**. The work line **112** is then removed from the tubular **24** leaving the bottom lift tool **100** in place with the stinger **106** engaged with the side pocket **42** in side pocket mandrel **34**. Thereby allowing the downward end of bottom lift injector **110** to descend to the depth desired by the operator. Typically such depth is lower than the lowest side pocket mandrel **34**, lower than packer **26**, and in many instances lower than perforations **16** in the casing **12**.

High pressure gas flow from the annular region flows through inlet **45** and into stinger **106** as depicted by arrow **121** the high pressure gas flow then continues upwards in the stinger **106** through high pressure swivel **104** and into high pressure link **103** as depicted by arrow **123**. The high pressure gas then continues on upward through high pressure swivel **102** and into the coil tubing of **128** bottom lift tool **100** where it is directed back downwards through the coil tubing **128** as depicted by arrow **125** the high pressure gas then continues downward through the bottom lift injector **110** as depicted by arrow **127** until it is injected into the fluid column as depicted by arrow **129**.

In certain instances, such as when a stinger replaces the gas lift valve **106** in the bottom lift tool **100**, a gas lift valve, nozzle, or other flow restriction may be placed at any location in the bottom lift tool **100** such as in the bottom lift injector **110** or in the body **108** of the bottom lift tool **100**.

In other instances the stinger **106** may incorporate a gas lift valve, nozzle, or other flow restriction while also allowing gas to flow into the bottom lift tool **100** then down through the coil tubing **128** to the bottom lift injector **110**. By utilizing a gas lift valve in the stinger **106** as well as a gas lift valve or other nozzle in bottom lift injector **110** at least two separate gas lift locations may be utilized. Additionally, the coil tubing **128** may incorporate gas lift valves, nozzles, or other flow restrictions along its length thereby allowing numerous gas lift injection sites along the length of the coil tubing **128** before the high pressure gas reaches the bottom lift injector **110**. Multiple gas lift injection sites along the length of the bottom lift injector **110** are particularly useful when the bottom of the production tubular **24** or the packer **26**, as indicated in FIG. **13**, are far from the producing formation **17**, as indicated in FIG. **13**, for example 1000 feet.

FIG. **13** depicts a bottom lift tool **100**, such as the bottom lift tool **100** depicted in FIG. **12**, having an extended length coil tubing **128** with a bottom lift injector **110**, which may incorporate a gas lift valve or other nozzle to regulate the gas flow through the nozzle and further includes a first gas lift valve **130** and a second gas lift valve **132** along the length of the bottom lift injector **110**. The bottom lift tool **100** is depicted in casing **131** that is cemented by cement **132** in the well **134**. As depicted the casing **130** does not extend to the formation zone **17** in practice the casing **130** may or may not extend to the formation zone **17** and may or may not be cemented to formation zone **17**. Depending upon the operation any number of gas lift valves may be used along the length of the coil tubing **128**. Additionally the lower end of the bottom lift injector **110** may incorporate an additional gas lift valve, a nozzle, or may remain open so that gas may exit the lower end of the bottom lift injector **110**. The operator may desire multiple gas lift injection sites along the length of the coil tubing **128** as it connects to the bottom lift injector **110** in those instances when the coil tubing **128** connecting the body **108** of the bottom lift tool **100** to the bottom lift injector **110** is extremely long and having a single gas lift valve or nozzle at only the lower end of the bottom lift injector **110** would be insufficient or impractical.

In another embodiment the release device **114** may be a fishing neck. The release device **114** may be an overshot or **108** have an internal or external polished bore receptacle, thereby allowing coil tubing to fluidically engage and inject gas or fluids such as chemicals to unload the well or treat the well for other production problems. Additionally, the release device **114** in addition to having an internal or external polished bore receptacle or in some instances in place of having a polished bore receptacle may provide an electrical power or data connection. By providing an electrical power or data connection a downhole data device to record and transmit data such as temperature, pressure, and valve state may be communicated to the surface. The electrical power or data connection could be a wet connect or by induction.

In practice a typical gas lift system reaches its production limits when the fluid level from the well is reduced to a level below the lowest gas injection point. Because gas lift wells typically use the annular region between the casing in the production tubular to provide high pressure gas and the bottom of this annular area must be packed off the bottom of the production tubular or at least the packer must be above the perforations in the casing. The operator may allow for production logging, by setting the packer far enough away from perforations to be sure that he is above the perforations. In practice the packer may be set 100 or 1000 feet above the perforations thereby leaving the lowest gas injection point 100 or even 1000 feet above the perforations. Operators would prefer to produce all of the fluids from a well at least down to the perforations in the casing. A method of producing this remaining column of liquid calls for running a work line into the well to remove the gas lift valve in the side pocket mandrel. Then running back into the well with the bottom lift tool to stab the bottom lift tools stinger into the side pocket mandrel accessing the high pressure gas in the annular region. The high pressure gas is then routed into the stinger upwards into the body of the tool through flexible conduit or flexible joints then back down towards the bottom of the well or at least to the perforations through the bottom lift injector which may be of smaller diameter coil tubing such as three-quarter inch or 1 inch coil tubing.

Bottom, lower, or downward denotes the end of the well or device away from the surface, including movement away from the surface. Top, upwards, raised, or higher denotes the end of the well or the device towards the surface, including movement towards the surface. While the embodiments are described with reference to various implementations and exploitations, it will be understood that these embodiments are illustrative and that the scope of the inventive subject matter is not limited to them. Many variations, modifications, additions and improvements are possible.

Plural instances may be provided for components, operations or structures described herein as a single instance. In general, structures and functionality presented as separate components in the exemplary configurations may be implemented as a combined structure or component. Similarly, structures and functionality presented as a single component may be implemented as separate components. These and other variations, modifications, additions, and improvements may fall within the scope of the inventive subject matter.

The invention claimed is:

1. A gas lift apparatus comprising:

a gas connection adapted to access a gas port in a side pocket mandrel in a well,

a tubular having a first end, a second end, and at least two pivots,

wherein the first end is connected to the gas connection,

further wherein the tubular is able to direct a gas lower in the well,

a bottom lift injector having an upper end and a lower end,

wherein the upper end is connected to the tubular,

further wherein gas flowing from the side pocket mandrel is directed into the gas connection then into the tubular then into the bottom lift injector and then out of the bottom lift injector.

2. The gas lift apparatus of claim **1** wherein, the gas connection is a gas lift valve.

3. The gas lift apparatus of claim **1** wherein, the gas connection is adapted to connect to a gas lift valve in the side pocket.

4. The gas lift apparatus of claim **1** wherein, the at least two pivots are a hose.

5. The gas lift apparatus of claim **1** wherein, the gas connection and the at least two pivots are a single piece.

6. The gas lift apparatus of claim **1** wherein, the lower end of the bottom lift injector extends below the side pocket mandrel.

7. The gas lift apparatus of claim **1** wherein, the lower end of the bottom lift injector extends below a packer below the side pocket mandrel.

8. The gas lift apparatus of claim **1** wherein, the lower end of the bottom lift injector extends below the lower end of the bottom lift injector extends below a hole allowing access to the formation zone.

9. The gas lift apparatus of claim **1** wherein, the lower end of the bottom lift injector is connected to a gas valve.

10. The gas lift apparatus of claim **1** wherein, the bottom lift injector has at least two nozzles.

11. A gas lift method comprising:

connecting a gas connection to a gas port in a side pocket mandrel in a well,

flowing a gas from the side pocket mandrel through the gas connection into a tubular;

wherein the tubular has a multiplicity of pivots,

wherein the pivotable tubular is able to direct the gas lower in the well,

directing the gas into a bottom lift injector,

directing the gas out of the bottom lift injector.

12. The gas lift method of claim **11** wherein, the gas connection is a gas lift valve.

13. The gas lift method of claim **11** wherein, the gas connection is adapted to connect to a gas lift valve in the side pocket.

14. The gas lift method of claim **11** wherein, the at least two pivots are a hose.

15. The gas lift method of claim **11** wherein, the gas connection and the are a single piece.

16. The gas lift method of claim **11** wherein, the lower end of the bottom lift injector extends below the side pocket mandrel.

17. The gas lift method of claim **11** wherein, the lower end of the bottom lift injector extends below a packer below the side pocket mandrel.

18. The gas lift method of claim **11** wherein, the lower end of the bottom lift injector extends below the lower end of the bottom lift injector extends below a hole allowing access to the formation zone.

19. The gas lift method of claim **11** wherein, the lower end of the bottom lift injector is connected to a gas valve.

20. The gas lift method of claim **19** wherein, the bottom lift injector has at least two nozzles.

* * * * *